

NIST Technical Note 2113

Developing Cost Functions for Estimating Solar Photovoltaic System Installed and Life Cycle Costs Using Historical Quote Data

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David Webb
Joshua Kneifel
Cheyney O'Fallon
*Applied Economics Office
Engineering Laboratory*

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Abstract

Residential solar photovoltaic (PV) system installations have become more prevalent as the installed cost has decreased over the last 10 years while system performance has improved. As these installations have increased, so too has interest in determining their economic value to a homeowner. PV installation cost estimates have typically assumed the entire cost as marginal (average cost per watt) using reported data aggregated to a state or country. This study implements a cost function that includes a fixed cost and marginal cost element to account for differences in cost structures while controlling for panel quality and specific location. The analysis uses county level installed quote data applied to estimate cost functions and apply these functions to life cycle cost analyses of the Washington DC-Maryland-Virginia (DMV) metropolitan area while incorporating state and county level differences in pricing and incentives. The estimated cost function is found to provide an installed cost estimate that is statistically different than using the traditional total average cost per watt approach for both standard and premium systems up to 9 kW and 11 kWh, respectively. The analysis finds no statistical difference in the installed cost function across counties, but clear differences in the life-cycle cost-effectiveness to a homeowner due to state policies and retail electricity prices. Absent financing, only PV systems in DC are life-cycle cost effective compared to retail electricity due to DC's strong solar renewable energy credit (SREC) market. PV can be cost effective in Maryland if financing and incentives are applied while no combination of financing or incentives makes PV cost effective in Virginia due to its lower relative electricity prices. Sensitivity analysis finds that the homeowner's assumed discount rate and the upcoming phase out of the federal investment tax credit (ITC) has a significant impact on residential PV economics.

Key words

Solar Photovoltaics; Life Cycle Cost Analysis; Net Present Value; Statistical Analysis, Solar Markets.

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1. Introduction

Solar photovoltaic system installations (PV) for residential homes have expanded significantly since 2010. Analysis from the National Renewable Energy Laboratory (NREL) finds that total installations per year in the United States increased from less than 50 000 in 2010 to over 350 000 in 2016 [1]. The data indicates a dip in 2017, but still over 300 000 new systems were installed. Given the increasing prevalence of PV, economic analysis (both current and projections) of PV systems is becoming increasingly important to understand the nature of the market.

A key driver of the growing deployment of residential PV systems has been the decrease in the installed cost to a homeowner. The reported national average installed cost of residential PV systems has decreased from nearly \$10/W in 2008 to ~\$3.70/W in 2017 [1]. The average cost has decreased due to reductions in costs for all cost categories (PV panels, inverters, balance of systems (BoS), and “soft costs” such as customer acquisition and margins) as well as economies of scale from larger median array installations (grown from ~4.2 kW_{DC} in 2008 to 6.3 kW_{DC} in 2017) and improved technology such as higher median efficiency panels (grown from 14 % in 2008 to 17% in 2017). The downward trend in prices and increasing size of residential PV arrays appears to have continued in 2018 and 2019 as the quoted average installed costs of \$3.05/W with average system size of 9.6 kW in the second half of 2018 and a further reduction in cost in 2019 thus far at \$2.98/W [2].

The quoted prices have been consistently lower than the reported realized installed costs by \$0.36/W to \$0.54/W (9 % to 14 %), which could be driven by numerous factors. We will highlight two here. First, the two prices may be capturing different types of customers and markets. Second, the quoted prices represent potential future system installations that may not be reported for one or two years. When comparing the reported median installed costs to the average quoted cost, the quoted estimates appear to be a relatively good projection for future reported installation costs using a 2-year lag as shown in Figure 1.

Based on technical modeling, NREL has estimated the engineering-based benchmark (technically feasible) price to be \$2.70/W [3]. The modeled benchmark installed costs has been consistently below the reported installed cost (\$0.73/W to \$0.98/W) since 2013. Their benchmark cost has been decreasing at a slower rate year-over-year (\$0.14/W in 2018) as the installed prices get closer to the technically feasible cost estimates. Assuming a 4-year lag on the benchmark to align it with the installed and quoted costs can be used for a projection of future average installed costs (Figure 1).

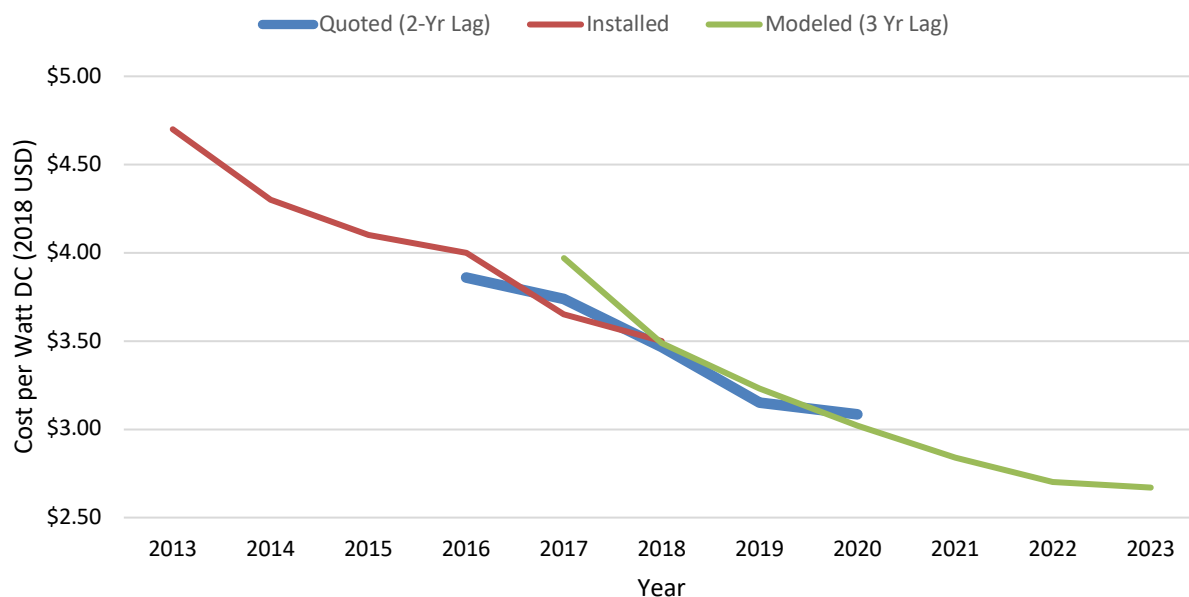


Figure 1. Installed Cost versus Quoted Cost (2-Year Lag) versus Modeled (4-year Lag)

Although this national trend is important, the decision to install a PV system is specific factors related to a homeowner's location. Barbose, Darghouth, LaCommare, Millstein and Rand (1) shows that the average installed cost across 19 states in 2017 ranges from \$2.60/W to \$4.50/W. Similarly, EnergySage (4) shows the average quoted price for 12 states ranging from \$2.72/W to \$3.43/W in the second half of 2018. There is a potential for even greater market variation across administrative and jurisdictional lines (county, city, or neighborhood level). These differences are a result of numerous factors, including customer demand/awareness, market development stage, state and local labor rules, laws, and regulations, and other regional effects.

To date, cost data has typically been reported on an average cost per watt basis. This approach makes sense when most of the costs are associated with each installed watt (solar panels and inverters). However, as these costs have become a smaller, there is potential for costs not directly associated with the size of the system (fixed costs, costs associated with the complexity of the system, differences in system quality) to account for a greater share of overall costs. For example, the median reported installed price for a system with 16 % to 18 % efficiency panels is \$3.60/W versus \$4.20/W for 20 % to 21 % efficiency panels [1]. Fixed costs (e.g. customer acquisition costs, permitting and commissioning) may vary based on the state or county system approval processes and the awareness of customers. Markets that are well developed with multiple installers realize lower margins, and therefore lower installed costs to homeowners [5].

This study uses a unique dataset of PV installer quotes provided to homeowners through the EnergySage platform to consider location-specific pricing (county level) for the Washington, DC metro area (DC-Maryland-Virginia or DMV), which includes Washington, DC and the four surrounding counties: Montgomery County and Prince George's County in Maryland, and Arlington County and Fairfax County in Virginia. By using quoted cost estimates, it provides a more up-to-date or even forward-looking economic analysis. This study is based

on a case study using the National Institute of Standards and Technology (NIST) Net-Zero Residential Test Facility (NZERTF), which was constructed to study the impact of different technologies on the performance of a “typical” residential structure in Gaithersburg, Maryland in Montgomery County. While the house is limited to its physical location, the data from the NZERTF has been used to examine other physical locations by incorporating data from other similar climates [6].

The study uses an ordinary least squares regression model to: determine if there are significant differences in the “county”-level markets (including Washington DC); create a non-linear cost (but linear in parameters) model to account for higher-order or interaction terms for each unique market; and compare to the typical linear cost estimate approach. These cost models will then be used to evaluate whether each unique market has a significant trend over time in the quoted installed costs. This analysis is coupled with a lifecycle cost analysis (LCCA) utilizing the results of the county market analysis to determine the economic feasibility of a system located in each county.

2. Literature Review

Several organizations provide installed cost data for residential PV systems, most notably the Lawrence Berkeley National Laboratory (LBL), the National Renewable Energy Laboratory (NREL), and EnergySage. NREL provides the annual Tracking the Sun report [1] and have published numerous reports and journal articles evaluating PV market structure (O'Shaughnessy (7), O'Shaughnessy (8)). NREL reports contain trends analysis in technology installation including recent historical data (1 to 2 years old) and modeled engineering-based (technically feasible) cost estimates. EnergySage provides bi-annual summaries of installer quotes provided in its online customer platform. The key specifics of the included data are found in the Methodology section, but they include varying technology options, locations of the system, the size of the system, among various other energy, engineering, location, and financial information. Quotes are more representative of current and near-term future installed costs because they are estimates for systems not yet installed. Using this data provides a reasonable expected installed cost for the next year, providing current or forward-looking analysis as opposed to backward looking (historical).

These resources are insightful into the general trends of the installed cost of residential markets for PV in the United States but are generalized over large markets in most cases and focus only on installation costs. The monetary benefits of PV are dispersed over the life of the system and some costs do not accrue immediately (maintenance, replacement, grid access fees and tariffs). Economic analysis can properly account for these future costs and many prior studies have evaluated the net present value (NPV) and internal rate of return (IRR) of residential PV.

An older case study in Denmark found that investments in energy efficiency were more effective than in renewable technologies [9]. PV with a heat pump was cost-optimal for a Net-Zero structure in a dense city area while PV with district heating is the highest LCC due to high operation and maintenance costs. In terms of energy efficiency, the best performing system was a PV system coupled with a solar thermal system and solar heat pump, although it was not optimal in terms of LCC. Another study in Canada found that PV could not achieve payback in 60 years unless the initial price of electricity increased by greater than 5

% per year using a 4 % discount rate [10]. This increases to 78 years with a higher discount rate equal to the inflation rate. A study with a focus on Singapore reached similar conclusions, finding residential PV to have a higher LCC than utilizing grid-based electricity [11].

More recent studies have found PV to be more economically viable. Swift (12) examined the economics of PV by looking at locations across the United States, including specific incentives, electricity rates, and solar insolation. The IRR ranged from 31.6 % in Honolulu to 8.3 % in Minneapolis. By varying the installed cost of PV, the authors also estimated the required installed cost to make PV economically attractive based on IRR. Parity with grid produced electricity with and without incentives was found to be location specific. A study published in 2015 found that PV was an attractive investment in many countries even in the absence of incentives [13], once again showing highly location specific variability. Farias-Rocha, Hassan, Malimata, Sánchez-Cubedo and Rojas-Solórzano (14) examined the economic feasibility of PV in the Philippines by focusing on the minimum feed-in tariff, the viability of net metering, and any additional support mechanisms that would be useful for supporting PV. The authors found that a 100 kW feed-in tariff would be profitable for a solar investor if the tariff does not drop below 4.20 PHP/kWh. A 1.89 kW system was found to be financially attractive using net metering alone. A recent Canadian study examining urban deployment of rooftop PV found 96 % of identified suitable rooftops would be profitable using NPV [15]. Recent studies in India have found PV to be financially viable for residential systems [16] and rural areas [17] while a study in Spain found utilizing grid electricity and natural gas for heating to be more economical than PV coupled with solar thermal and a micro-CHP system [18]. A more recent study for the United States by Lee, Hong, Koo and Kim (19) found that, depending on state and incentive, the payback period for select states in the United States ranges from as high as 25 years (Nevada and Wisconsin) to as few as 5 years (Hawaii). Maryland and Washington DC, which are most relevant to this study, had payback periods of 18 and 10 years, respectively. These differing results indicate both the improving economics of residential PV systems and the impact of regional differences when examining the LCC of PV systems.

Several studies also examine the impact of various incentives on the economics of PV. A study for the European Union examined the impact of various incentives, such as feed-in tariffs, net metering, capital subsidies, grants and rebates, and green tags [20]. The study examined multiple countries for both wind and PV, finding that depending on what incentives were available and how they were implemented, incentives can vary from beneficial to inconvenient for renewable energy sources. A partial rework by the authors expanded the number of countries considered and focused solely on feed-in tariffs finding the same basic results [21]. This finding is echoed in Dusonchet and Telaretti (22). Sow, Mehrdash, Rousse and Haillot (23) found that, for Canada, incentives allowed projects to remain feasible (based on 2016 data) with the only exception being projects in Montreal.

United States based studies also include the examination of Solar Renewable Energy Credits (SRECs). Burns and Kang (24) examined the early state of many SREC markets, finding them to be potentially strong, though the uncertainty associated with them proved to be a major drawback. Specifically, the SREC market had a higher present value than any other incentive examined (ITC, net metering, state tax credits), but the fluctuation in prices meant any benefit was highly uncertain. At the time of the study (2012) these benefits had a

variable effect based on energy price, with less incentive required when net metering was available, while PV in Ohio was still not economically competitive due to the state's lower energy prices. An analysis examining uncertainty in the cost-effectiveness of residential PV found that incentives that reduce the uncertainty in PV returns were generally the most effective [25]. The study, focused on Massachusetts, found uncertainties that lead to delays in investment timing and the discounted benefits of PV needed to exceed investment cost by 60 % to trigger investment. A study focusing on the United States as a whole found that the impact of incentives lead to a highly variable profitability index by state [19].

This study expands the literature in four ways. First, we statistically estimate non-linear cost functions for residential PV systems using the most recent data available. Second, the DMV market is evaluated for disaggregated county level differences in the cost of solar. Third, a LCCA is completed using the cost functions while controlling for state policy variations. Finally, a sensitivity analysis is completed for two key parameters in the LCCA (discount rate and federal solar tax credit).

3. Methodology

3.1. EnergySage Dataset

The analysis uses a unique dataset provided by EnergySage (26). EnergySage aggregates quotes for solar installations from multiple PV installers provided to homeowners on its online platform for January 2013 through November 2018. Although versions of this dataset have been used before [27], this analysis is fundamentally different in that it focuses on installer pricing and firm size. Figure 2 provides a map of where quotes are located by ZIP code for the District of Columbia-Maryland-Virginia counties. Note that ZIP codes do not perfectly map to county boundaries.

Capitol Area EnergySAGE Quotes

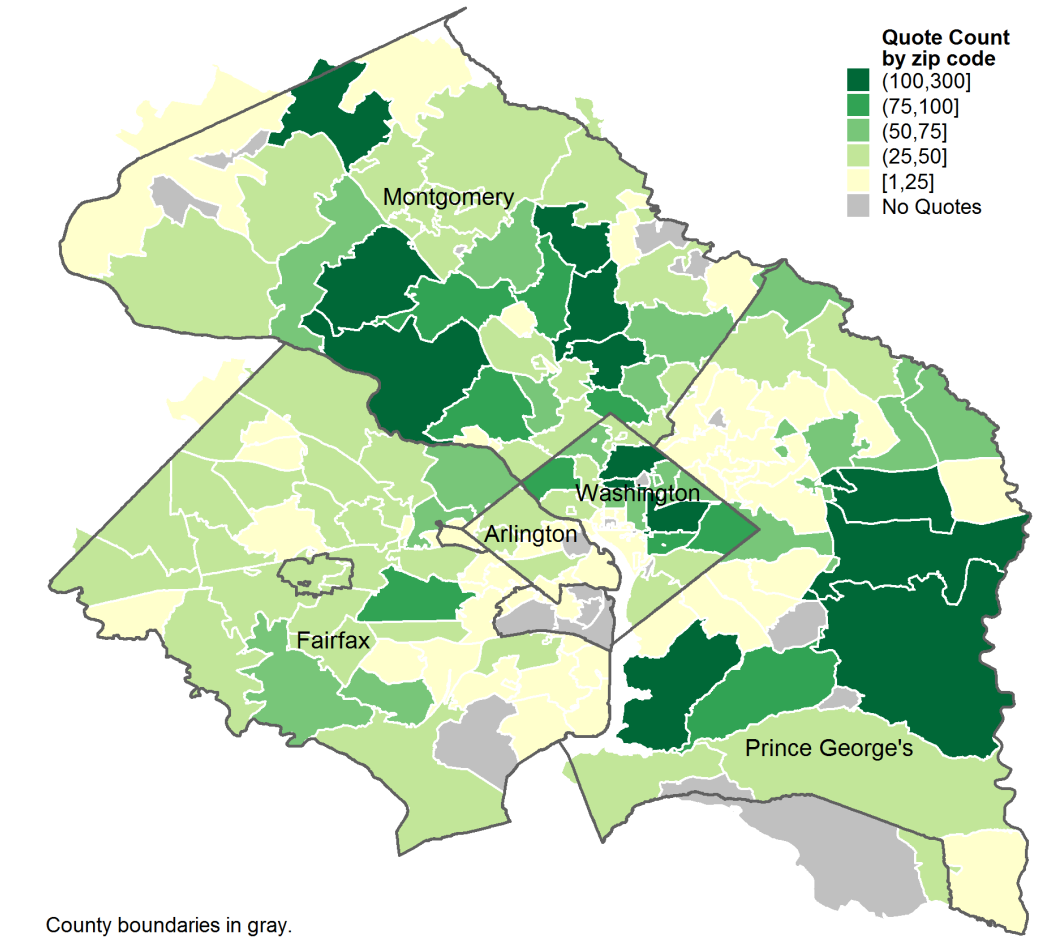


Figure 2. Heat map of number of quotes by ZIP code¹

The dataset includes several variables for each quote, the most pertinent to the current analysis being:

1. Quote Date (*Year*)
2. System Size in Watts (*Size*) – Direct Current in Watts (W_{DC})
3. Quote for Purchase Price (*Quote*) in USD²
4. System Quality in Six Qualitative Tiers: economy, economy plus, standard, standard plus, premium, premium plus (*Tier*)

There were issues with the data due to the voluntary nature of the data input.

1. System Quality (*Tier*) is not consistently reported for all years and occasionally within tiers
2. Tiers do not always have a sufficient number of data points to allow analysis
3. Some quotes do not contain a quote price

¹ Figure made using ArcGIS

² Quotes are used because reported installed prices are not available; a quote does not always end in a purchase.

To address the first issue a separate category for any non-tier list system is created and labeled Tier 0. This leads to the possibility of a mixture of systems in the Tier 0 category, and therefore the Tier 0 system quotes are excluded from any analysis that includes the tier variables. The second issue is resolved by aggregating the provided tiers (non-Tier 0 labeled quotes) into a three-tier classification of economy with economy plus (labeled *Economy* from this point on), standard with standard plus (labeled *Standard* from this point on), and premium with premium plus (labeled *Premium* from this point on). Given the prevalence of standard and premium systems, there were not enough economy system quotes to include in the analysis, and therefore, are excluded. Issue three required dropping the no value quotes from the analysis as there was no way to determine the true value of the quoted system.

Data was provided for the District of Columbia (*DC*) and the four surrounding counties; Arlington County, Virginia (*AC*), Fairfax County, Virginia (*FC*), Montgomery County, Maryland (*MC*), and Prince George's County, Maryland (*PG*). As a matter of simplification, any reference to "counties" as a collective, lacking further specification, includes *DC*. The analysis focuses on rooftop residential PV and excludes non-residential systems or those whose mounting system was not "penetrating rooftop" from the analysis.

Three types of inverters appear in the data set after filtering: *Micro*, *String*, and *Optimizer*. After filtering by all other options there were too few *Micro* and *String* inverters to get consistent statistically significant results from the analysis (*AC* had only 9 total observations for *String* inverters for 2018, while *AC* and *FC* had zero *Standard* tier *Micro* inverters for 2018). As such the analysis herein is limited to the *Optimizer* subset, which is the most commonly quoted and has an increasing market share for inverter type in the EnergySage data. Most systems quoted in 2018 have either a microinverter or optimizer. Additionally, systems with optimizers and microinverters have similar overall installed costs [1]. The historical data on installed systems supports this decision as well, with optimizers and microinverters accounting for ~40 % of installed systems each (over 80 % total) in 2017 and the fraction of systems using optimizers increasing year-over-year at a faster rate than microinverters [1]. Therefore, this restriction should be a reasonable representation of the market systems and costs. A further filter was applied to remove those systems over 50 000 W_{DC} ³ to account for overly influential points in sparse data regions as well as erroneous data entries relative to the defined filters. After all filters were applied the sample contained 4105 data points for 2015 to 2018.⁴

3.2. Statistical Analysis

The EnergySage dataset is analyzed using ordinary linear regression with robust standard errors to account for the heteroskedasticity apparent in Figure 3 where cost has greater variability as the system size increases. Some of the samples do not exhibit heteroskedasticity, however robust standard errors simplify to ordinary standard errors in such cases. The linear trendline for the entire EnergySage dataset shows a fixed costs (constant) of \$1457 and a variable cost of \$3.02/W.

³ While states define residential cutoffs via legislation these are not used to determine the initial cutoff, as the purpose is to determine the cost function based on install, not based on legislative preference. Future work will examine how legislative cutoffs impact installer pricing.

⁴ 2013 and 2014 are omitted because there are three and zero observations, respectively.

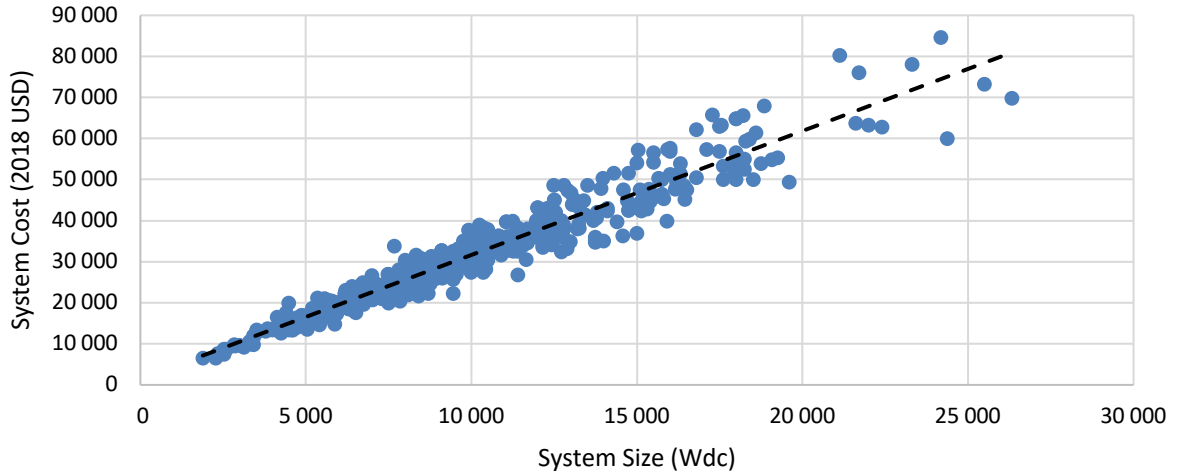


Figure 3. Relationship between System Size and System Cost displaying Heteroskedasticity

Two models are developed. The first focuses on evaluating a trend in the DMV region over time to determine if there is a statistical trend in total, fixed, and variable costs over time in hopes to allow for projecting future cost functions. The second evaluates the difference across counties and quality tiers for the most recent data (2018) to determine the location- and quality-related cost differences in current installed costs.

Interactions between variables were used to determine the significance of any difference between values. In examining the change in cost from 2015 to 2018 the regression model in Equation 1⁵ was developed. In this case all tiers (including Tier 0) are used in the regression to generate statistically significant regressions back to the initial year of the data (2015). No attempts were made to break out county or tier rating interactions because the goal of the initial regression was to look at the entire DMV region.

$$Quote_i = \alpha_1 * Size_i + \alpha_2 * i.year \# Size_i + \alpha_0 + \varepsilon_{i0} \quad (1)$$

Where α_0 represents the regression constant while all other α_i variables are regression coefficients for category i , and ε_{i0} represents an error term that is assumed to be normally distributed with a mean of zero with heteroskedasticity. The # symbols represent interactions based on multiplying variables. $i.year$ is an index variable for year. To determine whether all years were significantly different the $i.year$ variable was rotated through every possible base year. Doing so allows all possible relationships between individual years to be tested for significance. These results can be found in Appendix A. The $i.year$ variable is omitted because regressions indicated that it was not statistically significant, implying that fixed costs are not changing over time (2015 to 2018) in the DMV region. In this model α_0 represents fixed costs and α_1 represents marginal costs. α_2 is an adjustment to the marginal cost based on the interaction term.

The regression in Equation 2 was specified to identify significant county and tier level differences. Results from this regression were also used in the subsequent LCCA and is

⁵ $i.year$ is omitted from this model as it was found to be insignificant (5 % level of significance) when controlling for the interaction effect. The form here is the most comparable to the current means of estimating solar PV costs.

focused on the most current data. As such the regression in Equation 2 was limited to 2018 data.

$$\begin{aligned} Quote_i = & \beta_1 * Size_i + \beta_2 * i.County + \beta_3 * i.Tier + \beta_4 * i.Tier\#Size_i + \beta_5 \\ & * i.County\#Size_i + \beta_6 * i.County\#i.Tier + \beta_7 \\ & * i.County\#i.Tier\#Size_i + \beta_0 + \varepsilon_{i1} \end{aligned} \quad (2)$$

Where any variable preceded by an i represents an indicator variable, β_0 represents the regression constant while all other β_1 variables are regression coefficients and ε_{i1} represents the error term, assumed normally distributed with a mean of zero but heteroskedastic. $i.County$ and $i.Tier$ are index variables for the county and tier, respectively. The reference levels for *County* and *Tier* are *DC* and *Standard*, respectively. *Size* is a continuous. In this model β_0 represents fixed costs and β_1 represents marginal costs while all other coefficients represent adjustments to the marginal cost due to the interaction variables. Additional regressions were run based on the results of Equation 2. The form of these regressions can be found in the Analysis section.

3.3. Lifecycle Cost Analysis

LCCA is a method to calculate the total cost of a purchase over time by accounting for all cash flows over the entire life of a system or investment. The LCCA uses the β_0 (fixed cost) and β_1 (variable cost) variables from each statistically viable county-tier combination as the initial installed cost per watt. Since the most recent estimates are most pertinent, only the 2018 data is used. This analysis assumes that the homeowner maintains possession of the house for the useful life of the PV system⁶. The analysis results may change if a different study period is selected.

The costs included in the LCCA are:

- Initial install cost
- Electricity consumption cost
 - Positive if consumption is larger than generation for the year
 - Negative if consumption is less than generation for the year
- Operation and Maintenance cost (*O&M*)
- Replacement Costs for:
 - Solar Panels (Optimizer panel inverters are assumed to have the same life as the panels and are replaced at the same time)
 - Optimizer central inverter
- Residual Value (Linear proration of remaining value)
- Solar renewable energy credits (*SRECs*)

The 30 % renewable energy tax credit (ITC) is included, although it will begin to be phased out in 2019.

⁶ The assumed PV system lifetime is 25 years while the median tenure length for homeowner in a home is 13 years [28] Emrath P (2013) The “Right” Rate of Return for Energy Efficiency. (National Association of Home Builders).. Therefore, an alternative approach would be to complete the analysis for a 13-year study period and use resale value premium estimates (e.g. [29] Hoen B, Wiser R, Adomatis S, Jackson T, Graff-Zivin J, Thayer M, Klise GT (2015) SELLING INTO THE SUN: PRICE PREMIUM ANALYSIS OF A MULTI-STATE DATASET OF SOLAR HOMES. (Office of Energy Efficiency and Renewable Energy, Solar Energy Technologies Office, U.S. Department of Energy).) as the residual value.

Two methods of purchasing the system are considered, an all cash purchase and financing. It's typical for an installer to offer their own financing option or a power purchasing agreement (PPA). While the EnergySage data contains whether a financing or PPA was offered it does not provide the terms. Financing can be completed through a bank loan, allowing a generic financing option to be derived that does not require matching financing options to specific installers (or developing an average set of loan terms) in the EnergySage data. Establishing a standard *PPA* is not feasible because they are unique to solar financing and are omitted from the analysis.

All analyses were run using an adjustment to the NZERTF PV system, which has a rated capacity of 10.2 kW. This capacity was reduced to “right-size” the system, meaning the rated capacity is roughly equivalent to the predicted energy consumption for the first year of installation. The NZERTF system uses a string inverter, however the analysis herein will assume that an optimizer is used in the modeling to match the EnergySage data. Estimates for solar production come from the System Advisor Model (*SAM*) [30] and the NZERTF specifications. Energy consumption data is derived from a simulation model of the NZERTF run through EnergyPlus.

As multiple counties are considered, the rules for compensation for excess generation for each county are used as appropriate. These are tariff riders for the energy providers contract and are based on relevant state laws. Whether SRECs are available and their value are derived from the National Renewable Energy Laboratory's annual *Tracking the Sun* report [1] and SolSystems SREC contract options [31].

A cash flow for the full study period is generated by incorporating the individual costs for each category by year and then discounted to 2018 dollars using the equation below for net present value of a single cash flow and annual discounting where d is the discount rate and p is the timing of the cash flow.

$$\text{Discounted Value} = \frac{\text{Cash Flow}}{(1 + d)^p}$$

The total of these discounted cash flows is summed to obtain the present value cost of the system for both purchase options (cash and loan).

Cash formula:

$$LCC = \text{Installed Cost} + \text{Electric Costs} + \text{O\&M} + \text{Replace Costs} - \text{RV} - \text{ITC} - \text{SREC}$$

Loan formula:

$$LCC = \text{Down Payment} + \text{Loan Payments} + \text{Electric Costs} + \text{O\&M} + \text{Replace Costs} - \text{RV} - \text{ITC} - \text{SREC}$$

Sensitivity analysis relative to the discount rate and the ITC tax credit were performed to understand how these two parameters impact the LCCA.

4. Analysis

4.1. Statistical Analysis

Table 1 contains the result of the Equation 1 regression with 2015 as the reference year⁷. The regression results for the remaining iterations through each reference year may be found in Table 14 in Appendix A.

Table 1. Equation 1 Regression Results⁸

Regression Variable Coefficient	Coef.	Robust Std. Err.	t	P>t	[95% Conf. Interval]	
Size (\$/kW _{DC})	2.943	.0673	43.74	<0.000	2.811	3.075
Year#Size						
2016 (\$/kW _{DC})	0.0607	0.0636	0.95	0.340	-0.0640	0.185
2017 (\$/kW _{DC})	-0.339	0.0653	-5.19	<0.000	-0.467	-0.211
2018 (\$/kW _{DC})	-0.119	0.0623	-1.90	0.057	-0.241	0.00351
Constant (\$)	1409	215.0	6.55	<0.000	987.2	1830

The results suggest that 2016 marginal costs are not statistically different than 2015, while marginal costs are statistically different for 2017 and 2018.⁹ Rotating the reference year produces significant differences for all marginal costs except for the 2015 and 2016 result found already (see Table 14). The trend displayed in the data is a constant marginal cost from 2015 to 2016 followed by a drop in 2017 which shows no statistically significant change in 2018. The fact that the p-value for 2018 is significant at a 10 % level suggests it is worth investigating in a future model with a larger data set, especially considering that the coefficient for 2018 is larger when compared to 2017 and could be an effect of the solar tariffs implemented in 2018. However, it fails to meet the determined cutoff (5 % level of significance) for significance here and is not discussed further.

An analysis was also run for the total average cost per watt by year for comparison purposes to the non-linear cost model (Table 2). Like the Equation 1 regression, the results in Table 2 do not account for differences in quality or county. These results show a similar trend, with 2015 and 2016 being similar, a decrease from 2016 to 2017, followed by an increase in 2018. The primary difference is that using the total average cost per watt¹⁰ (\hat{X}) assumes that the entirety of the PV system price is marginal, ignoring any fixed costs of installation. Therefore, the mean costs are consistently higher (6 % to 9 %) than the marginal cost estimates using the cost function developed in Table 1. The focus of this paper is not on total average cost per watt (as reported in prior studies) and no difference in means hypothesis testing was completed. Thus Table 2 is meant only for a cursory comparison.

⁷ The R² value is 0.9829

⁸ R² is equal to 0.9387

⁹ At a 10 % LoS

¹⁰ As based on the statistical mean in lieu of the conditional mean calculated in the regression

Table 2. Statistical Moments of marginal cost by year

Year	Average Size	Standard Deviation Size	Average USD/W	Stand. Dev. USD/W	Marginal Cost from Regression	Difference between Average USD/W and Marginal Cost from Regression
2015	7695	4255	3.21	0.36	2.94	0.27 (9 %)
2016	9371	4297	3.18	0.32	3.00	0.18 (6 %)
2017	9203	4317	2.75	0.40	2.60	0.15 (6 %)
2018	10 454	5238	3.02	0.36	2.82	0.20 (7 %)

The results of the regression in Equation 2 are provided in Table 3 (statistically significant coefficients are shaded).¹¹ For reference there are 1108 *Standard* panel systems and 1026 *Premium* panel systems. Between counties there are 73 systems in AC, 517 systems in DC, 622 systems in FC, 639 systems in MC, and 306 systems in PG.

¹¹ R² value equals 0.9614

Table 3. Results of Equation 2 Regression with DC as the Base County

Regression Variable	Coef.	Robust Std.	t	P>t	[95% Conf. Interval]	
County						
AC	410.9	956.9	0.43	0.668	-1466	2287
FC	38.34	745.4	0.05	0.959	-1423	1500
MC	-611.9	1163	-0.53	0.599	-2892	1668
PG	-40.10	817.7	-0.05	0.961	-1644	1564
Tier	886.4	636.0	1.39	0.164	-360.9	2134
Size	2.786	0.0640	43.57	<0.000	2.661	2.912
County#Tier						
AC#Premium	1146	1810	0.63	0.527	-2403	4696
FC#Premium	511.0	1090	0.47	0.639	-1626	2648
MC#Premium	285.9	1325	0.22	0.829	-2313	2885
PG#Premium	-280.8	1104	-0.25	0.799	-2445	1884
County#Size						
AC	-0.167	0.117	-1.43	0.154	-0.396	0.0625
FC	-0.135	0.0856	-1.58	0.115	-0.303	0.0330
MC	-0.0865	0.131	-0.66	0.51	-0.344	0.171
PG	-0.129	0.0928	-1.39	0.164	-0.311	0.0528
Tier#Size						
Premium	0.122	0.0828	1.47	0.141	-0.0405	0.284
County#Tier#Size						
AC#Premium	-0.0325	0.188	-0.17	0.862	-0.401	0.336
FC#Premium	0.0310	0.120	0.26	0.796	-0.204	0.265
MC#Premium	0.0156	0.150	0.10	0.917	-0.279	0.310
PG#Premium	0.0682	0.122	0.56	0.577	-0.172	0.308
Constant	1619	484.2	3.34	0.001	669.0	2568

The results in Table 3 indicate that County nor Tier have a significant impact on the regression constant. When County is interacted with Tier, no interaction has a statistical impact. County-Size interactions appear to have no significant impact as well, possibly indicating no regional differences. The only variables that have any impact are the Size variable and the regression constant. By iterating through the base county, all significant relationships between counties can be determined¹². This is unnecessary for the Tier variable since it only has two levels, so any hypothesis testing will only invert the sign of the test statistic, and under the normally distributed errors assumption will result in the same p-value. The same findings are apparent in every iteration.

While Table 3 is useful in looking at all possible combinations of the County, Tier, and Size variables, there is the possibility that it is overparametrized, confounding truly significant variables with non-significant variables. To test this concern, two less parametrized

¹² Regression Tables in Appendix A

regressions are considered. The first removes all county interactions from the regression as in Equation 3, while the other removes Tier interactions as in Equation 4.

$$Quote_i = \lambda_1 * Size_i + \lambda_2 * i.Tier + \lambda_3 * i.Tier\#Size_i + \lambda_0 + \varepsilon_{i3} \quad (3)$$

$$Quote_i = \delta_1 * Size_i + \delta_2 * i.County + \delta_3 * i.County\#Size_i + \delta_0 + \varepsilon_{i4} \quad (4)$$

Where λ_i and δ_i are regression coefficients, and ε_{i3} and ε_{i4} are the error term for the regression, assumed heteroskedastic and normally distributed with a mean of zero. The results of these two regressions are presented in Table 4 and Table 5.

Table 4. Results of Equation 3 Regression (Standard as Base Rating)¹³

Regression Variable Coefficient	Value	Robust Std. Err.	t	P>t	[95% Conf. Interval]	
Tier	1133	516.8	2.19	0.028	119.7	2147
Size	2.670	0.0481	55.47	<0.000	2.576	2.765
Tier#Size						
Premium	0.157	0.0559	2.81	0.005	0.0476	0.267
Constant	1611	442.4	3.64	<0.000	743.1	2478

Reducing the parameters in each regression yields a better illustration of the predominant factors impacting the installed cost. *County*, as evident in Table 5, has no significance at the 5 % level in Equation 4, while *Tier* is statistically significant in Equation 3 (Table 4). Based on this we may conclude that at a 5 % LoS, the price for a solar PV system is independent of county (limited to the counties and year examined in the data sample), but dependent on the quality of the panel¹⁴. This allows the results of Table 4 to be used across all counties, treating the five-county region as a single market¹⁵ for the purposes of the LCCA. Using the Akaike Information Criterion (AIC) and the Bayesian Information Criterion (BIC) the *Tier* based regression (AIC = 40 182, BIC = 40 204) is preferable to the *County* based regression (AIC = 40 552, BIC = 40 608).

¹³ R² is equal to 0.9604

¹⁴ Given that PG and FC both show statistically significant interactions with *Size* at a 10 % LoS, it is possible that county level differences exist for the marginal costs. For the purposes of this study 5 % was used as the cutoff. Future work should verify this result.

¹⁵ A geographical analysis to check for subcounty differences was not performed and is left for future work.

Table 5. Results of Equation 4 Regression (DC as base County)¹⁶

Regression Variable Coefficient	Value	Robust Std. Err.	t	P>t	[95% Conf. Interval]	
County						
AC	371.4	974.5	0.38	0.703	-1540	2282
FC	-337.5	604.7	-0.56	0.577	-1523	848.4
MC	-781.7	594.0	-1.32	0.188	-1947	383.2
PG	-329.6	578.6	-0.57	0.569	-1464	805.0
Size	2.892	0.0386	75.03	<0.000	2.817	2.968
Size#County						
AC	-0.0631	0.111	-0.57	0.571	-0.281	0.155
FC	-0.114	0.0639	-1.78	0.075	-0.239	0.0113
MC	-0.0877	0.0664	-1.32	0.187	-0.218	0.0425
PG	-0.107	0.0627	-1.70	0.089	-0.230	0.0162
Constant	1982	295.6	6.71	<0.000	1403	2562

Plotting the two *Tier* regression yields Figure 5. The error bars represent the 95 % confidence intervals. As would be expected, the premium systems have a slightly higher fixed (\$2744) and marginal cost (2.827 \$/W), resulting in a difference in price from the *Standard* panels (\$1611 fixed and 2.670 \$/W marginal) that increases with system size. The price based on the average quote price for 2018 is also included for comparison. The average cost in Figure 5 differs from that in Table 2 as the former includes all filters applied to the regressed data, while the latter does not. The greatest differences between the cost functions and the mean cost per watt estimate occur for smaller *Premium* systems and larger *Standard* systems. The mean cost approach leads to overestimates for *Standard* systems > 5 kW while underestimating for premium systems < 18 kW. For the mean system size (10 454 W), the mean cost estimate is 3.7 % higher (\$1127 with a 95 % Confidence Interval (CI) of [\$717, \$1527]) and 5.4 % lower (\$1651, 95 % CI of [\$1319, \$2022]) than the cost function estimates for the *Standard* and *Premium* tiers, respectively.

¹⁶ R² is equal to 0.9531

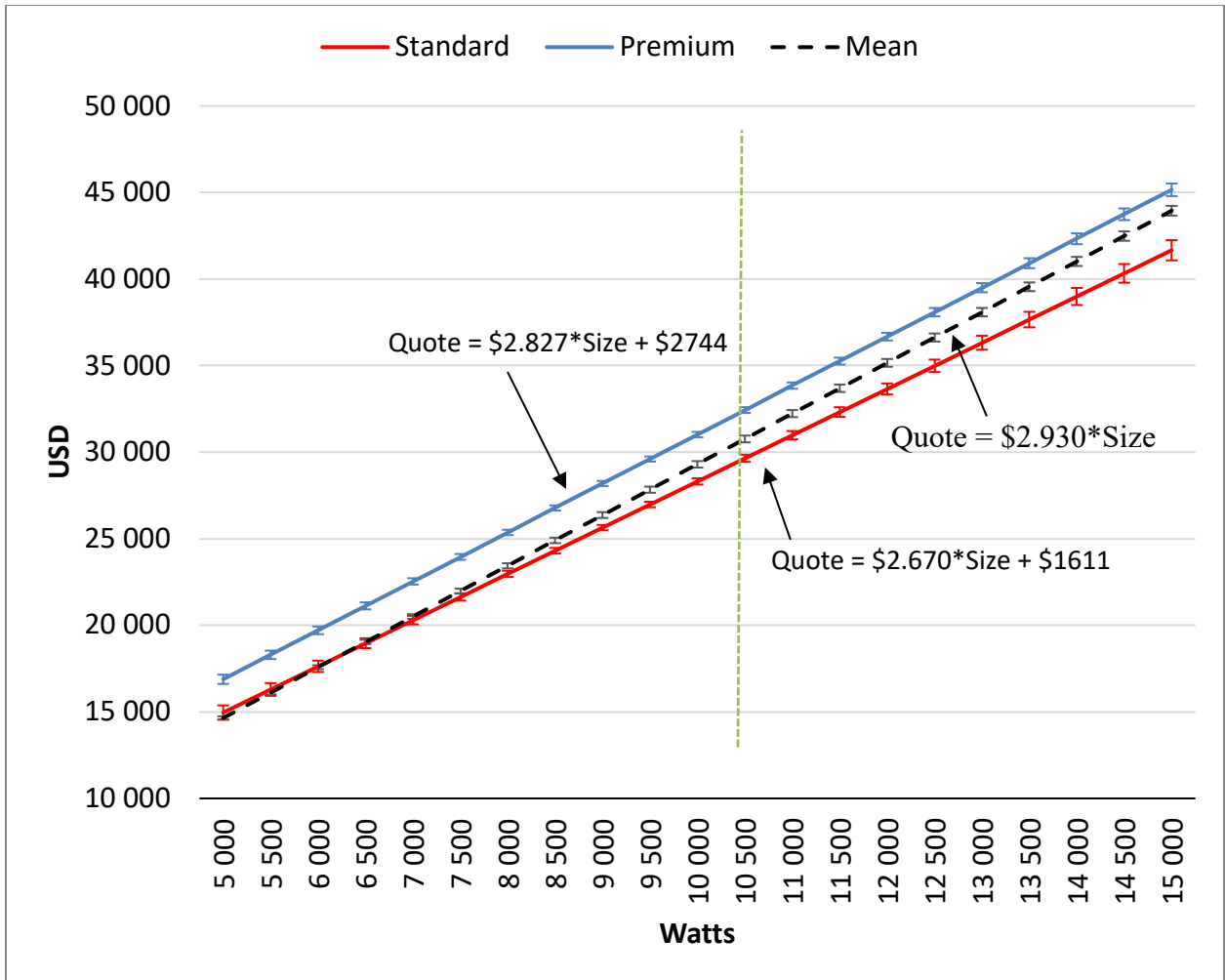


Figure 4. Plot of cost functions

This comparison does not control for system quality because most reported average cost per watt estimates are aggregated across all systems regardless of quality. Even after controlling for system quality in Figure 5, the estimated cost function is found to provide an installed cost estimate that is statistically higher (95 % CI) than using the traditional total average cost per watt approach for both *Standard* and *Premium* systems up to 9 kW and 11 kW, respectively. The cost estimate difference decreases as capacity increases. For example, the difference for a 5 kW *Premium* system is \$1739 while the difference for the mean-sized *Premium* system (10 454 W) is \$625. Note that the difference will converge to zero and then begin to increase with the cost function, leading to lower cost estimates than the average cost per watt approach at ~12.4 kW for the *Standard* system and ~13.8 kW for the *Premium* system.

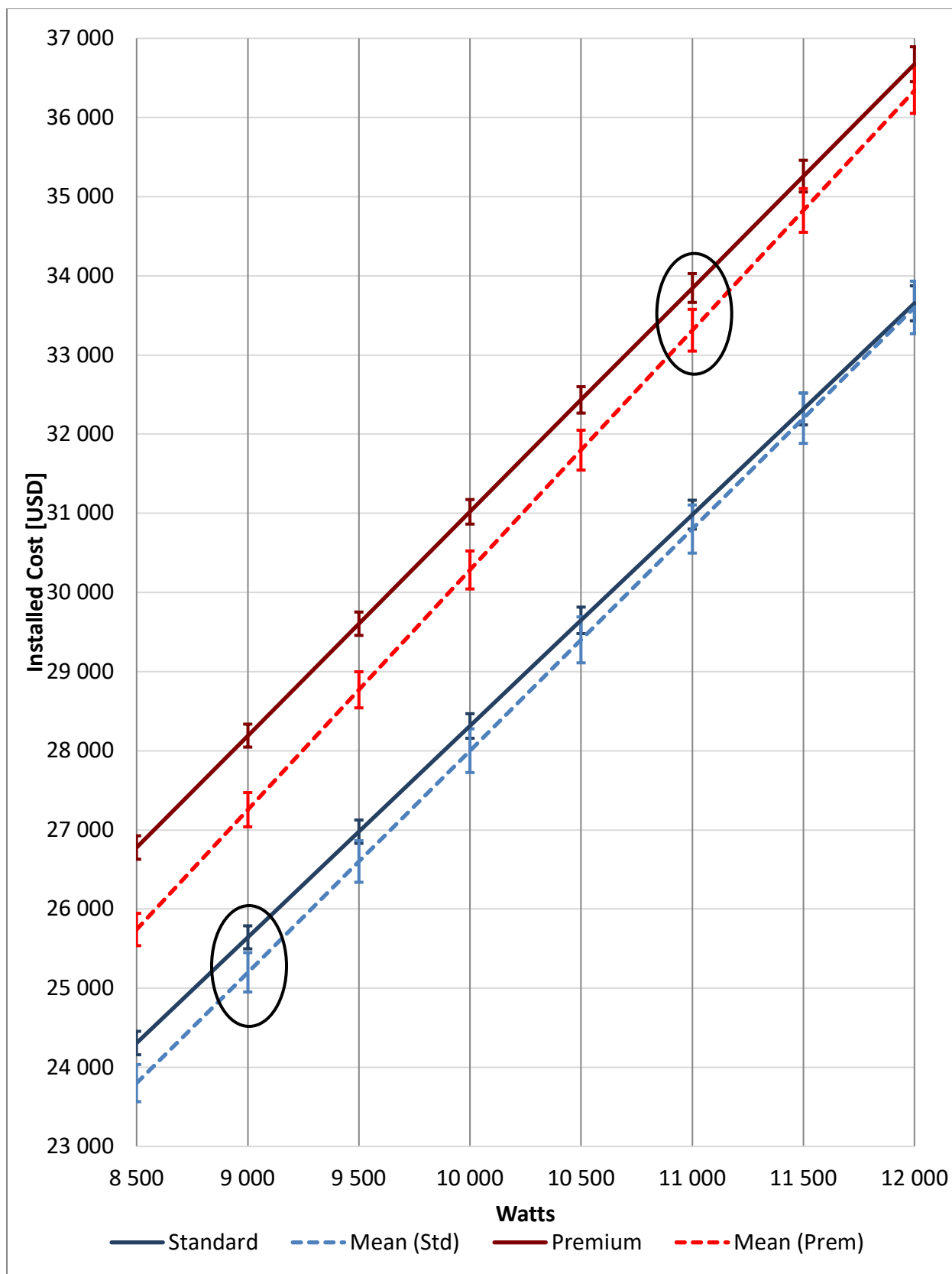


Figure 5. Plot of cost functions by Quality. Circles are meant to highlight key areas of statistical significance

4.2. LCCA Inputs

Table 6 contains the inputs for the LCCA shared by all counties while Table 7 contains county specific inputs. Data is collected from numerous sources, including electricity providers, government publications and software, and solar manufacturer equipment specifications.

Table 6. Inputs for LCCA shared by all Counties

Variable	Value	Source
System Size	8960 W _{DC} 28 Panels	NZERTF Panels (SunPower SPR-E19-320) adjusted to right size system. Values for capacity from SAM model at reference conditions.
Inverter	-DC Optimizer (8960 W _{AC}) -Cost – 0.06 \$/W _{AC}	-Assumed based on EnergySage Data -NREL [3]
PV Panel Life/Study Period	25 Years	SunPower warranty [32]
Optimizer Life	25 Years	From Solaris Technical Industry Inc. [33]
Central Inverter Life	12 Years	From Solaris Technical Industry Inc. [33]
Maintenance Cost	\$10 per panel (28 panels)	Upper value from HomeAdvisor [34] and lower value from Renew Economy [35].
Central Inverter Replacement Cost	0.18 \$/W _{DC}	NREL [3]
Cost	Standard – \$25 536 Premium – \$28 078	Calculated from Equation 3 Regression
Discount Rates	10 % nominal rate (stated preference) 1.8 % General Inflation Rate (Average as of May 2019)	- White Paper [28] - General Inflation Rate [36]
Weather File	TMY3 for Dulles International Airport ¹⁷	System Advisor Model ¹⁸ [30]
Federal Tax Credit	30 %	ITC [37]
Loan variables		
Down Payment	20 %	- Assumed
Nominal Interest Rate	7.5 %	- Assumed
General Inflation Rate	1.8 % (Average as of May 2019)	- General Inflation Rate [36]
Degradation	1.0 %/year First five years 0.4 %/year Every year after ¹⁹	SunPower warranty [32]
Residual Value	Value of expected production from end of study period to 40 years. Valued at retail rate	40-year life from SunPower [38]
Escalation Rate	South Region	U.S. Department of Energy [39]
Energy Production	12 235 kWh	System Advisor Model Output
Energy Consumption	11 684 kWh	EnergyPlus Model [40]

¹⁷ The Dulles International Airport TMY3 is used for all five counties. While doing so introduces some error in the PV generation due to the difference in latitude and solar radiation levels and errors in household consumption due to difference in weather patterns, the use of a single weather file allows for differences in regional policy and pricing to be better highlighted.

¹⁸ All inputs for SAM found in Appendix A

¹⁹ The SunPower warranty only extends to 25 years. The use of the 0.4 %/year for the residual value calculation is an author's assumption.

Table 7. Inputs for LCCA unique to each County

Variable	Value	Source
Energy Consumption Cost	<i>FC</i> – \$0.1104/kWh <i>AC</i> – \$0.1104/kWh <i>DC</i> – \$0.1282/kWh <i>MC</i> – \$0.1345/kWh <i>PG</i> – \$0.1342/kWh	<i>FC</i> – Electricity Local website [41] <i>AC</i> – Electricity Local website [42] <i>DC</i> – 12 Month average for 2018 [43] <i>MC</i> –Pepco bill for home in Gaithersburg, MD [44] <i>PG</i> –Southern Maryland Energy Cooperative [45]
Net Metering Policy	<i>MC, PG</i> – Net Metering with excess compensated at generation rate at the end of the year (\$0.07300/kWh for <i>MC</i> , \$0.0726/kWh for <i>PG</i> ²⁰). <i>DC</i> – Net Metering with excess credits rolling over month-to-month indefinitely ²¹ <i>AC, FC</i> – Net Metering with credits applied to next month's bill. Credits roll over up for a twelve-month period. At end of twelve-month period financial compensation only available through purchasing agreement with utility at avoided cost rate. Otherwise credits may roll over indefinitely.	<i>MC</i> – Current Pepco Tariff for MD [44] <i>PG</i> – Southern Maryland Electric Cooperative [45] <i>DC</i> – Current Pepco Tariff for DC [46] <i>AC, FC</i> – Virginia Department of Mines, Mineral, and Energy [47]
Non-Energy Monthly Charges	<i>MC</i> – \$7.959 /Mo <i>PG</i> – \$9.82 /Mo <i>DC</i> – \$15.09 /Mo <i>AC</i> – \$6.58 /Mo <i>FC</i> – \$6.58 /Mo	<i>MC</i> – Current rates [48] <i>PG</i> – Southern Maryland Energy Cooperative [45] <i>DC</i> – Current Pepco Tariff for DC [46] <i>AC/FC</i> – Current Dominion Energy Tariff [49]
SRECs²²	<i>MC/PG</i> – \$50/kW _{DC} (estimated) for 15 years paid upfront <i>DC</i> – \$1400/kW _{DC} (estimated) for 15 years paid upfront <i>AC/FC</i> – No established SREC market so no compensation is assumed ²³	<i>MC/PG</i> – From SolSystems [50] <i>DC</i> – From SolSystems [51] <i>AC/FC</i> – NREL [1]
State Grant	MD - \$1000; DC - \$0; VA - \$0	NC Clean Energy Technology Center (52)

Using the data from Table 6 the cost for the Standard system used in the LCCA is \$25 535 with a 95 % Prediction Interval (PI) of [\$19 891, \$30 392] and the Premium system has a cost of \$28 078 (PI of [\$24 192, \$33 390]). Prediction intervals were estimated using quantile regression at the 0.025 and 0.975 quantiles because of the way the robust standard errors were estimated to account for heteroskedasticity. While it is possible to propagate the uncertainty due to the prediction error using simulation or other uncertainty propagation techniques such as first order Taylor series approximations, doing so while ignoring the other sources of uncertainty in the LCCA (maintenance costs, SREC valuation, energy consumption and generation, replacement times) would provide an inaccurate representation

²⁰ <https://www.smeco.coop/account/residential-bill-calculator>

²¹ Roll over will occur at the end of the year for modeling purposes. The difference in this case is on the order of ones of dollars.

²² While SRECS will accrue and be owned by the system owner after the upfront period ends, predicting the state of the open SREC market is infeasible, therefore any SRECs earned after the upfront period ends are not considered in the LCC.

²³ In the absence of renewable targets there is little pressure on utilities to purchase SRECs. While compensation is possible under Virginia net metering policies there is no open market and little data on compensation rates.

of the true uncertainty for the LCCA. As such, uncertainty treatment in the LCCA is reserved for future work and all reported LCC values will be treated as deterministic.

The results of the LCCA for the No PV baseline (purchase electricity through the electric grid from a local provider) and the PV alternatives excluding incentives or financing are presented in Table 8. The *Standard* and *Premium* values include the residual value. Table 8 indicates that, absent incentives, the LCC of the No PV baseline is lower than that for the PV alternative regardless of county. This is not unexpected given the large upfront cost associated with PV installation and the discounting of future energy cost savings. Note that, PV LCCs are similar for all counties (within \$1000 for each *Tier*) because the LCC is largely driven by the marginal cost of installation and is therefore system size and quality dependent.

Table 8. LCCA Results

County	No PV LCC	Standard	Premium
MC	\$19 076	\$29 027	\$31 570
PG	\$19 274	\$29 269	\$31 812
DC	\$19 143	\$30 000	\$32 542
FC	\$15 664	\$29 110	\$31 652
AC	\$15 664	\$29 110	\$31 652

Table 9 summarizes the effects of incentives on the LCCA. The federal tax credit is available to all homeowners, and therefore provides the same value in all five counties. Counties in Maryland receive a \$1000 grant incentive while DC and Virginia do not receive a grant. The SRECs in DC have a large impact (\$11 615) while minimal to no impact in the other four counties (\$0 in Virginia and \$415 in Maryland).

Table 9. Reductions in LCC from Incentives

County	Tax Credits & Grants		SRECs		Total	
	Standard	Premium	Standard	Premium	Standard	Premium
MC	\$8661	\$9423	\$415	\$415	\$9076	\$9838
PG	\$8661	\$9423	\$415	\$415	\$9076	\$9838
DC	\$7661	\$8423	\$11 615	\$11 615	\$19 276	\$20 038
FC	\$7661	\$8423	\$0	\$0	\$7661	\$8423
AC	\$7661	\$8423	\$0	\$0	\$7661	\$8423

Table 10 summarizes the incentives and the impact on the LCCA. Except for DC (shaded in Table 10), the total LCC for the PV alternative is greater than the No PV baseline. This suggests that current incentives are not sufficient to overcome the high upfront cost of the PV installation given the LCC input value assumptions. *DC's* smaller LCC is due to the robust SREC market currently versus Virginia with no SREC market and the SREC market for Maryland (*MC* and *PG*) providing minimal financial incentives.²⁴ The Maryland counties

²⁴ With the passage Maryland SB 516 Maryland set a goal of 50 % renewable energy by 2030. This has the possibility of changing the nature of the SREC market for the state depending on how it is implemented. This work makes no predictions on what effects, if any, will result from the bill.

(*MC* and *PG*) are relatively close to being competitive (\$~900 for *Standard* and ~\$2700 for *Premium*, respectively) and, should a consumer find that one or more assumption in the LCCA is too conservative (e.g. discount rate), could be the best alternative for their situation. The Virginia counties (*FC* and *AC*) have a lower electricity consumption price than those in DC or Maryland, making PV less LCC competitive (>\$5000 for both PV alternatives and counties).

Table 10. Impact of reductions on Total LCC. Shaded entries are reductions in LCC relative to the No PV option

County	Total LCC after reduction		ΔLCC from No PV LCC	
	Standard	Premium	Standard	Premium
MC	\$19 951	\$21 732	\$875	\$2656
PG	\$20 193	\$21 974	\$919	\$2700
DC	\$10 721	\$12 504	-\$8422	-\$6639
FC	\$21 449	\$23 229	\$5785	\$7565
AC	\$21 449	\$23 229	\$5785	\$7565

Table 11 examines the impact of using financing to purchase the PV system excluding (1) and including (2) incentives. Since the interest rate is lower than the assumed discount rate, financing decreases total LCC by \$2495 (or \$2496 depending on rounding) for the *Standard* system and \$2745 (or \$2744 depending on rounding) for the *Premium* system. Using financing to pay for the initial installation results in a decrease in the total LCC to the point where the Maryland counties, if other incentives are applied, are the lowest LCC compared to the No PV baseline for both *Standard* and *Premium* systems. The Virginia counties, even with financing and incentives, cannot match the LCC of the No PV baseline. Given the dependence of financing on the interest rate and discount rate, which are both going to be individual based, it is impossible to make further statements on the applicability of this result to specific prospective PV purchasers.

Table 11. Effects of Financing on PV LCC. Shaded entries are reductions in LCC relative to the No PV option

County	Total LCC with Financing (1)		ΔLCC (1) from No PV LCC		Total LCC with Financing and Incentives (2)		ΔLCC (2) from No PV LCC	
	Standard	Premium	Standard	Premium	Standard	Premium	Standard	Premium
MC	\$26 531	\$28 826	\$7456	\$9750	\$17 456	\$18 987	-\$1620	-\$89
PG	\$25 133	\$29 067	\$7500	\$9793	\$17 697	\$19 229	-\$1575	-\$44
DC	\$26 844	\$29 798	\$8361	\$10 655	\$8228	\$9760	-\$10 915	-\$9384
FC	\$25 953	\$28 908	\$10 950	\$13 244	\$18 953	\$20 484	\$3289	\$4820
AC	\$25 953	\$28 908	\$10 950	\$13 244	\$18 953	\$20 484	\$3289	\$4820

A sensitivity analysis was performed to understand the impacts of discount rate on the LCCA. In lieu of the 10 % nominal (~8 % real, stated preference) rate, Siegel's constant (6.5 % to 7 % in real terms, revealed preference) is used for the LCCA [53]. Siegel's constant is the long-term average annual rate of return on stocks based on 200 years of data (1794 to 1994). The lower end of this range (6.5 %) was selected. Table 12 contains these results with

counties where PV is preferred to the No PV baseline are shaded. The lower discount rate does not change the relative performance of PV systems to the No PV baseline, but does further improve the economics of PV systems in all counties. Solar PV in *DC*, *MC*, and *PG* becomes even more LCC effective at the lower discount rate while PV in *FC* and *AC* remain unable to match the No PV baseline's LCC, although coming within \$2323 and \$3938 for *Standard* and *Premium* systems, respectively. Further reductions of \$0.26/W and \$0.44/W in marginal installed costs could make *Standard* and *Premium* systems, respectively, cost-effective in Virginia.

Table 12. LCCA results using a 6.5 % discount rate. Shaded entries are reductions in LCC relative to the No PV option

	LCC								
County	No PV	Total w/ No Incentives or Financing		Total After Incentives		Total using financing		Financing w/ Incentives	
		Std.	Prem.	Std.	Prem.	Std.	Prem.	Std.	Prem.
MC	\$21 816	\$28 896	\$31 438	\$19 815	\$21 594	\$27 680	\$30 101	\$18 598	\$20 257
PG	\$22 042	\$29 174	\$31 717	\$20 093	\$21 872	\$27 958	\$30 379	\$18 876	\$20 535
DC	\$21 892	\$30 036	\$32 578	\$10 597	\$12 376	\$28 819	\$31 241	\$9380	\$11 038
FC	\$17 914	\$29 114	\$31 657	\$21 454	\$23 233	\$27 898	\$30 320	\$20 237	\$21 896
AC	\$17 914	\$29 114	\$31 657	\$21 454	\$23 233	\$27 898	\$30 320	\$20 237	\$21 896

The results thus far are based on quote data from 2018, which may be a reasonable estimate for decisions in 2019 and (to a lesser extent in 2020) based on Figure 1. The analysis in this study can be used to provide some insight on the potential sensitivity of the LCCA results for the DMV area to the phase out of the federal tax credit. The exact ITC phase out schedule is: 2019 – 30 %, 2020 – 26 %, 2021 – 21 %, and 2022 – 0 %.

For the tax credit sensitivity analysis, the 10 % nominal (8 % real) discount rate is used. It also assumes that the cost function for 2018 produces a quote that an installer will be willing to honor for the full duration of the phase out (based on the EnergySage data 2020 is realistically the last viable year for this assumption) and that installers do not account for changes to the tax credit when quoting out systems. These assumptions are likely incorrect on their face, however predicting price trends from the current EnergySage data in a cost function form (several analyses predict price trends by treating the entire installation cost as marginal) is left for future work. Any results from the tax credit sensitivity analysis should therefore be understood to represent the sensitivity of a 2018 quote to future decreases in tax credits and not a prediction of future price trends or a predictive analysis of future PV systems. Table 13 summarizes the results of the tax credit sensitivity results.

Table 13 shows that in *DC*, with its strong SREC market, the tax credit is not required for PV to be the lowest LCC alternative regardless of whether financing is used. The *Premium* system in the Maryland counties required both financing and the 30 % ITC to be preferred to the No PV baseline. The *Standard* system remains preferred at the 26 % ITC but is no longer preferred when the tax credit drops to 21 %. No combination made PV the preferred alternative in the Virginia counties with the full tax credit applied and, therefore, there is no change in preference as it is phased out.

Table 13. Sensitivity of LCCA results to changes in the ITC. Shaded entries are reductions in LCC relative to the No PV option

Tax Credit	County	No PV LCC	PV LCC		Total After Incentives		Total using financing		Financing w/ Incentives	
			Std.	Prem.	Std.	Prem.	Std.	Prem.	Std.	Prem.
26 %	MC	\$19 076	\$29 027	\$31 570	\$20 973	\$22 855	\$26 532	\$28 826	\$18 477	\$20 110
	PG	\$19 274	\$29 269	\$31 812	\$21 215	\$23 097	\$26 774	\$29 067	\$18 719	\$20 352
	DC	\$19 143	\$30 000	\$32 542	\$11 746	\$13 627	\$27 504	\$29 798	\$9 250	\$10 883
	FC	\$15 664	\$29 110	\$31 652	\$22 470	\$24 352	\$26 614	\$28 908	\$19 975	\$21 607
	AC	\$15 664	\$29 110	\$31 652	\$22 470	\$24 352	\$26 614	\$28 908	\$19 975	\$21 607
21 %	MC	\$19 076	\$29 027	\$31 570	\$22 250	\$24 259	\$26 532	\$28 826	\$19 754	\$21 514
	PG	\$19 274	\$29 269	\$31 812	\$22 492	\$24 501	\$26 774	\$29 067	\$19 996	\$21 756
	DC	\$19 143	\$30 000	\$32 542	\$13 023	\$15 031	\$27 504	\$29 798	\$10 527	\$12 287
	FC	\$15 664	\$29 110	\$31 652	\$23 747	\$25 756	\$26 614	\$28 908	\$21 251	\$23 011
	AC	\$15 664	\$29 110	\$31 652	\$23 747	\$25 756	\$26 614	\$28 908	\$21 251	\$23 011
0 %	MC	\$19 076	\$29 027	\$31 570	\$27 613	\$30 155	\$26 532	\$28 826	\$25 117	\$27 411
	PG	\$19 274	\$29 269	\$31 812	\$27 855	\$30 397	\$26 774	\$29 067	\$25 359	\$27 653
	DC	\$19 143	\$30 000	\$32 542	\$18 385	\$20 928	\$27 504	\$29 798	\$15 889	\$18 183
	FC	\$15 664	\$29 110	\$31 652	\$29 110	\$31 652	\$26 614	\$28 908	\$26 614	\$28 908
	AC	\$15 664	\$29 110	\$31 652	\$29 110	\$31 652	\$26 614	\$28 908	\$26 614	\$28 908

The difference in LCC between the PV alternative and the No PV baseline can be used to estimate the additional drop in the installed price required to make a homeowner indifferent between the two alternatives as the ITC phases out. For Maryland, the *Standard* system is cost effective for a 26 % ITC but would require a drop in the installed cost of ~\$700 (\$0.08/W_{DC}) and ~\$6000 (\$0.67/W_{DC}) for the 21 % ITC and 0 % ITC, respectively. The *Premium* system would require a drop in the installed cost of ~\$1000 (\$0.11/W_{DC}), ~\$2500 (\$0.28/W_{DC}), and ~\$8400 (\$0.94/W_{DC}) for the 26 %, 21 %, and 0 % ITC, respectively. For Virginia, the *Standard* system would require a drop in the installed cost of \$3300 (\$0.37/W_{DC}), \$4300 (\$0.48/W_{DC}), \$5500 (\$0.61/W_{DC}), and \$10 970 (\$1.23/W_{DC}) for the 30 %, 26 %, 21 %, and 0 % scenarios.

5. Conclusion

Solar PV continues to be the most popular renewable energy source available to homeowners and it is, therefore, important to understand the economics of these systems. Because a substantial portion of the economics of these systems are a result of regional markets and local and state regulations, an examination of regional impacts is important. While studies of this kind have been done using simple averages for entire states, nations, or a single structure, this study focuses on the boundary between five jurisdictions including multiple PV installers with recent quote data. Political boundaries like those in the DC-Maryland-Virginia area allow for natural experiments in how different solar PV policies impact the cost effectiveness of installed systems. The use of cost functions in lieu of simple averages allows the fixed

costs of installation to be separated from the marginal costs, providing a better picture of how PV installation pricing works in practice.

In examining Washington DC and the four surrounding counties it's found that that solar PV pricing is largely similar for the region. A comparison of the estimated cost functions to the mean cost approach used by previous studies show the greatest differences for very small or very large systems depending on the quality tier. A difference of \$1127 (3.7 %, 95 % CI of [\$717, \$1527]) for the *Standard* system to \$1651 (5.4 %, 95 % CI of [\$1319, \$2022]) for the *Premium* system is found for the mean sized system (10 454 W). After controlling for system quality, the estimated cost function is found to provide an installed cost estimate that is statistically different than using the traditional total average cost per watt approach for both *Standard* and *Premium* systems up to 9 kW and 11 kWh, respectively. For upfront (cash) purchases, the LCC for the assumed PV systems remain higher for grid-based electricity for all counties except DC. DC has a strong SREC market, which allows it to overcome the substantial first costs associated with solar PV installation. With higher electricity prices, the Maryland counties find PV to be more competitive with grid-based generation than the Virginia counties, and can achieve LCC parity if incentives are applied. Greater reductions in solar PV installation costs are required for PV to remain LCC competitive absent financing and as the ITC begins to phase out. Alternatively, if the average discount rate associated with homebuyers were lower than that used in this study, then present value of future savings and gains would be higher, possibly maintaining cost competitiveness. Incorporating financing can make the assumed PV system viable for more counties assuming all incentives are also incorporated. Whether or not a potential purchaser can afford the initial down payment, or the monthly payments is an important constraint outside the scope of this paper.

This study highlights several areas of future work. Future studies should track changes in solar PV economics, regulations, and markets to understand how the LCC of PV systems evolves. Replicating this study using a broader dataset (i.e. 2019 data and other counties in Maryland and Virginia) could lead to more statistically significant differences across counties. The creation of predictive models that use a cost function in place of simple averages could help achieve more accurate estimates and allow for the dynamics of the tax credit expiration to be evaluated more effectively. More regional analysis covering a larger geographic area (or multiple geographic areas) is also vital to better understand how individual subregions differ and how their policies impact economic viability. Attempts to understand subcounty markets would also be useful, as energy and installation pricing varies within counties (i.e. neighborhood, specific house layout) and by installer. Alternative market structures may also exist (e.g. ZIP code clustering). Future attempts should also be made to get a sufficient number of solar PV installer financing options and *PPAs* to allow them to be modeled in the LCCA.

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Appendix A: Supplemental Materials

Table 14. Results of Iterating Base Year for Regression 1

Regression Variable Coefficient	2016 Base Year		2017 Base Year		2018 Base Year	
	Coef.	P>t	Coef.	P>t	Coef.	P>t
Size	3.004	<0.000	2.604	<0.000	2.824	<0.000
Year#Size						
2015	-0.0607	0.340	0.339	<0.000	0.119	0.057
2016	N/A	N/A	0.400	<0.000	0.179	<0.000
2017	-0.400	<0.000	N/A	N/A	-0.220	<0.000
2018	-0.179	<0.000	0.220	<0.000	N/A	N/A
Constant	1409	<0.000	1409	<0.000	1409	<0.000

Table 15. Results of Iterating Base Year for Regression 2

Regression Variable Coefficient	AC as Base County		FC as Base County		MC as Base County		PG as Base County	
	Coef.	P>t	Coef.	P>t	Coef.	P>t	Coef.	P>t
County								
DC	-914.4	0.343	-38.3	0.959	611.9	0.599	40.1	0.961
AC	N/A	N/A	876.1	0.385	1526	0.257	954.5	0.369
FC	-876.1	0.385	N/A	N/A	650.2	0.588	78.4	0.928
MC	-1526	0.257	-650.2	0.588	N/A	N/A	-571.8	0.646
PG	-954.5	0.369	-78.4	0.928	571.8	0.646	N/A	N/A
Tier (Premium)	2033	0.231	1397	0.114	1172	0.313	605.5	0.502
Size	2.619	<0.000	2.651	<0.000	2.670	<0.000	2.657	<0.000
County#Tier								
DC#Premium	-1146	0.527	-511.0	0.639	-285.9	0.829	280.8	0.799
AC#Premium	N/A	N/A	635.2	0.74	860.2	0.676	1427	0.457
FC#Premium	-635.2	0.740	N/A	N/A	225.1	0.878	791.9	0.531
MC#Premium	-860.3	0.676	-225.1	0.878	N/A	N/A	566.8	0.700
PG#Premium	-1427	0.457	-791.9	0.531	-566.8	0.7	N/A	N/A
County#Size								
DC	0.167	0.154	0.135	0.115	0.0865	0.510	0.129	0.164
AC	N/A	N/A	-0.0322	0.777	-0.0805	0.594	-0.0378	0.750
FC	0.0322	0.777	N/A	N/A	-0.0483	0.706	-0.00567	0.949
MC	0.0805	0.594	0.0483	0.706	N/A	N/A	0.0427	0.748
PG	0.0378	0.750	0.00567	0.949	-0.0427	0.748	N/A	N/A
Tier#Size								
Premium	0.0894	0.596	0.153	0.076	0.138	0.272	0.190	0.035
County#Tier#Size								
DC#Premium	0.0325	0.862	-0.0310	0.796	-0.0156	0.917	-0.0682	0.577
AC#Premium	N/A	N/A	-0.0635	0.737	-0.0482	0.818	-0.101	0.598
FC#Premium	0.0635	0.737	N/A	N/A	0.0153	0.920	-0.0372	0.765
MC#Premium	0.0482	0.818	-0.0153	0.920	N/A	N/A	-0.0526	0.733
PG#Premium	0.101	0.598	0.0372	0.765	0.0526	0.733	N/A	N/A
Constant	2533	0.002	1657	0.003	1007	0.341	1578	0.017

Table 16. Inputs for System Advisor Model²⁵

Variable	Input	Variable	Input
Location of TMY3 Weather File²⁶	Dulles International Airport	Modules per String	1
Sky Diffuse Model	Perez	Strings in Parallel	28
Weather File Irradiance Data	DNI and DHI	Number of Inverters	1
Module	SunPower SPR-E19-320	Shading and Snow	Omitted
Mounting Configuration	Rack	Losses	Default for DC Optimizers
Heat Transfer Dimensions	Module Dimensions	Lifetime	0.5 %/year degradation rate
Inverter²⁷	SolarEdge Technologies SE9K 208V ²⁸ [CEC 2013]	Angle of Inclination	18.4 % based on NZERTF

²⁵ Any variable not listed here is either kept as default or not used, including all financial variables

²⁶ Also determines latitude for solar irradiance calculation

²⁷ Optimizer is assumed to be attached to the panel and is not explicitly modeled by SAM

²⁸ 208 Voltage is rare in new construction; however, the grid voltage has minimal impact on the PV generation, and it is assumed that the inverter would be scaled to system size. Therefore, the listed inverter is used.